APPLICATION OF RESERVOIR CHARACTERIZATION AND ADVANCED TECHNOLOGY TO IMPROVE RECOVERY AND ECONOMICS IN A LOWER QUALITY SHALLOW SHELF SAN ANDRES RESERVOIR

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ABSTRACT

The Oxy West Welch Project is designed to demonstrate how the use of advanced technology can improve the economics of miscible CO_2 injection projects in lower quality shallow shelf carbonate reservoirs. The research and development phase (Budget Period 1) primarily involved advanced reservoir characterization. The current demonstration phase (Budget Period 2) will implement the reservoir management plan for an optimum miscible CO_2 flood design based on the reservoir characterization.

Although Budget Period 1 officially ended 12/31/96, reservoir characterization and optimum flood design has continued into the first part of Budget Period 2. Specifically, the geologic model was enhanced by integration of the 3-D seismic interpretations. This resulted in improved history match by the simulator and more accurate predictions of flood performance on which to base the project design.

The majority of the project design work has been completed, material specifications provided and bids solicited. Preparation of the demonstration area is well underway.

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EXECUTIVE SUMMARY

The West Welch Unit is one of four large waterflood units in the Welch Field located in the northwestern portion of Dawson County, Texas. The Welch Field was discovered in the early 1940's and produces oil under solution gas-drive mechanism from the San Andres formation at approximately 4800 ft. The field has been under waterflood for 30 years and a significant portion has been infill drilled on 20-acre density. A 1982-86 pilot CO_2 injection project on the offsetting South Welch Unit yielded positive results. The recent installation of a CO_2 pipeline near the field allowed the phased development of a miscible CO_2 injection project at the South Welch Unit.

The reservoir quality is poorer at the West Welch Unit due to its relative position at sea level during deposition. Because of the proximity of the CO_2 source and the CO_2 operating experience that would be available from the South Welch Unit, West Welch is the ideal location for demonstrating methods for enhancing economics of IOR projects in lower quality shallow shelf carbonate reservoirs.

The West Welch project is divided into two phases; Budget Period 1 and 2. Budget Period 1, which ended 12/31/96, involved a detailed reservoir characterization effort which attempted to integrate advanced petro physics with 3-D seismic and cross well tomography to identify major flow units and their interwell distribution. The resulting geologic model was used in the reservoir simulator to forecast the performance as a basis for developing an optimum CO_2 miscible flood design. Budget Period 2 covers the installation and actual field demonstration of the project.

Some of the reservoir characterization and project design carried over into Budget Period 2. The bulk of the reservoir characterization work during the third annual reporting period (8/4/96 - 8/3/97) involved refinement of the seismic-guided mapping and integration of this mapping into the geologic model. The resulting enhanced geologic model allowed the simulator to achieve a better history match and was further refined by improved relative permeability curves that accounted for hysterises. The rock typing was also revised. The result was a better deterministic model which provided a more accurate performance projections for use in optimizing the miscible CO_2 project design.

Work was also continued on interpretation of the cross well seismic data. Although none of the tomograms have yet been integrated into the geologic model, it appears that the interpretation is progressing to the point where the cross well seismic can be utilized in the reservoir characterization.

Based on the optimum project design, material specifications were prepared for bid solicitation. Much of the well work has been completed including the drilling of a well which completes the south injection pattern. Actual construction of facilities is underway and CO_2 injection is projected to began October 1997.

DISCUSSION

FRACTURE STIMULATIONS

Cost estimates for two sizes of fracture treatments were obtained for the injection wells in the project area. The fracture treatments will be done during the early part of Budget Period 2 with the purpose of improving injectivity and sweep improvement of the CO_2 flood. The smaller jobs were designed for the north area where the wells have been infilled with the larger jobs designed for the injectors in the south area where wells are on wider spacing.

3-D SEISMIC INTEGRATION

The second stage of the geologic modeling involved the integration of the 3-D seismic data and the well data to capture the interwell porosity variations portrayed by the seismic interpretations. The seismic data over the project area has been used to generate porosity and porosity thickness maps for the two main pay intervals[1]. These properties were then distributed to the geologic model layers using the average porosity distribution from the closest available wellbores for the distribution of porosity at the particular bin location [2]. Initial simulation runs using this enhanced model resulted in a good match with historical total fluid production, indicating that the integration of seismic data improved the characterization of rock properties such as porosity and permeability. However, the forecasted water/oil ratio was low to the historical rates (i.e. oil production too high and water production too low) suggesting a problem with relative permeability and/or floodable pay.

The seismic-generated maps were used in an attempt to determine locations of barriers to waterflooding. Areas on the maps that showed rapid decreases in porosity were interpreted as barriers to flow. These apparent barriers were inserted in layers 1 through 4 in the geologic model, but they had little impact on the forecasted oil recovery. Next, the barriers were extended through additional layers. The final simulation results reduced the model's oil production by only 500-600 thousand barrels of oil, which still did not match actual performance.

Another approach to locating barriers was to use the seismic cross-sections to determine where flat spots or unusual reductions in the seismic troughs occurred. This approach gave results similar to the seismic-generated map method, both in terms of the barriers location and the reduction in the simulator forecasted oil production. Barriers are not the only parameters controlling the water/oil ratio, so the accuracy of the barrier location from seismic data can not be judged at this time.

Several wells were drilled outside the project area based on the latest seismic-guided porosity maps. The porosity logs showed an average porosity within ½ of a porosity unit of the predicted value from the seismic-guided mapping. The mapping has identified additional locations just south of the project area that could be developed.

CROSS WELL SEISMIC

Shear wave and vertical seismic profile (VSP) processing completed on the 15 lines. The results show the shear wave data has more detail than the compression wave lines.

Due to the nature of the earth, where the rock density increases with depth, for reflection surveys the ray path is actually bent or curved leading to problems in placing the reflection event at the proper depth. Changes to the processing software corrected this curvature, allowing the reflections and calculated velocities to be placed at the proper depth which improved the correlation of seismic and wellbore data.

Because the reflected signals are very weak, additional work to remove noise and interfering wave train components has improved the reflection surveys. Examples of the most recent results are shown in Figs 1 and 2 which display the images for an interval from 4800 ft to 5000 ft, referenced at the source well. Traces are shown at one-foot lateral spacing and are zeroed above 4800 ft. Figure 1 is in the north between WWU7916 (source) and the WWU7914 (receiver) where the reservoir quality is poorer and more heterogeneous. The section shown starts about 200 ft from WWU7916 and extends about 100 ft to the northwest. In general, the reflection peaks match the dense zones and troughs match the porous zones on the 7916 neutron-density log. There is also a general correlation between the seismic section and the porosity log on WWU7914. The density log shows negative porosity values in the same depth range as the amplitude peaks on the seismic. Two peaks can be seen merging in the central portion of this section, showing a significant geologic change that could be trapping oil.

Figure 2 covers a reservoir interval that is considered to be more uniform than the section in Fig 1. The same 4800 ft to 5000 ft interval and one-foot lateral trace spacing are shown. The images suggest a more uniform reservoir section than Fig 1.,which agrees with the depositional model.

The quality of seismic data gathered from the fifteen line survey varies greatly between lines and even along individual lines. For this reason, the effort has focused on lines 1,2,7,9,11,12, and 13 which contain the best data. Three of these lines are from the north pattern and four from the south pattern. Rotating the phase along individual trace segments was required to compensate for the random orientation of the receivers. The revised sections on the seven lines are showing realistic-looking seismic anomalies with 8-10 ft vertical resolution.

Synthetic seismograms were generated from sonic and density logs on WWU3210, WWU4852, and WWU7916 and used to check the correlation of the cross well reflections.

NUMERICAL SIMULATIONS

A radial model was set up to simulate the water alternating gas (WAG) injection test run in the WWU4816w injection well. The objective was to obtain a history match of the field test by adjusting the relative permeability hysterises curves. Alternating three-day injection periods of CO_2 followed by water then CO_2 again were run and the relative permeability adjusted until the bottomhole injection pressures measured during actual injection were matched. The resulting relative permeability hysterises curves were input into the full area model to simulate the WAG cycles to be evaluated. Using the exact curves from the radial model proved impossible and the new hysterises curves had to be adjusted closer to the original model curves for the full model to run to completion.

The simulator used the new hysterises curves to predict the performance of several scenarios to determine an optimum operating plan for the project which would maximize the economics. A continuous CO_2 injection case was run to aid in designing the CO_2 distribution system. Figure 3 shows the forecasted production for three scenarios. The continuous case assumes continuous CO_2 injection three years before switching to alternating one month water then one month CO_2 WAG injection. The base case assumes six months of continuous CO_2 before changing to the 1:1 WAG injection. The fracture case is identical to the base case except the eight injection wells in the south had high permeability values applied east and west for four gridblocks from the wellbore gridblock to simulate a 400 ft fracture.

The base geologic model was enhanced by incorporating seismic data to define the interwell properties. Since the seismic traces were on approximately the same spacing as the model grids, reservoir properties of porosity and permeability were available at each grid block. The multipliers to porosity and/or permeability were not applied as in the base model which only used wellbore values. This enhanced model produced the correct volumes of total fluid, but the water/oil ratio was wrong.

The first change attempted to the seismic model was the addition of flow barriers based on seismic data as previously described. This did not produce sufficient change in the produced fluid ratio, so net-to-gross pay ratio was investigated. Dimensionless type curve analysis [3] indicated that a net-to-gross pay multiplier needed to be applied to certain spots in the project area. Under initial injection or producing conditions a well exhibits a decline in production or injection based on the total pore volume connected to the wellbore. Once steady state conditions are reached the decline stabilizes and and the connected pore volume between injector and producer controls the flow. By assuming a unit mobility ratio during waterflooding and ratioing the initial permeability-thickness to the steady state permeability-thickness, the net to gross multiplier resulted. The analysis gave good results when the production or injection wells were operating under reasonably stable conditions which prevent the generation of “noise”.

The oil/water ratio match was improved by changing the mix of relative permeability rock types to modify the relative permeability relationships with only slight changes in the actual relative permeability curves. This change increased the overall residual oil saturation to waterflood. Higher oil saturation and the larger pay volume resulting from elimination of net/gross pay modifiers resulted in a larger volume of oil available as a CO_2 target.

The mix of relative permeability rock types is a critical factor in obtaining a good oil recovery forecast. Initially, the rock types were designated by layer based on dominance of the computed wettability from well logs. Further review showed that the oil wet pores affected the well logs far more than the actual percentage of oil wet pores present. Therefore, the relative permeabililty rock type was changed to the predominant rock type (water wet) expected from the geologic interpretation. This shows the laboratory scale rock types do not easily scale up to the scale of simulator grids.

The revised model was used to forecast CO_2 performance which projected an increased recovery compared to the base model. A larger volume of CO_2 will be required to realize the higher recovery. The performance forecast also showed a significant drop in production rate in the early life of the CO_2 flood. This comes about as a result of reducing injection pressures to stay below formation fracture gradient. To prevent this drop from occurring, injection rates have been cut back during the 2nd quarter of 1997 to allow reservoir pressures to stabilize at a lower pressure prior to CO_2 injection. As a result of lower injection pressures, total fluid production dropped from 6,790 barrels per day to 6,417 barrels per day in only 48 hours with no measurable change in oil rate.

ECONOMIC ANALYSIS

The simulation performance forecasts for the various operating scenarios were converted to cash flow projections for evaluation purposes. This required estimation of development and operating costs and a forecast of future prices ($19.09/Bbl oil and $13.39/Bbl NGL escalated at 4%/annum from 11/1/97). The project economics for the fracturing case using the WWU10 equation of state and the base geologic model was one scenario. Under this scenario, an additional two million barrels of oil were recovered over a 14 yr period. The gross CO_2 utilization was 17.4 MCF/Bbl. The indicated gross (no DOE funding) project economic indicators were a 13.8% annual rate-of-return and a 7.4 yr. payout. Modifying the equation of state reduced the rate of return to 5.8% and reduced recovery to 1.5 million barrels of oil. With this change the CO2 utilization ratio increased to 19.0 MCF/Bbl.

Additional economic analyses were performed on the revised forecasts resulting from the enhancement of the geologic model. The gross project economics gave a 42.3% annual rate-of-return with a 4.1 yr payout. The CO2 utilization ratio reduced to 11.0 MCF/Bbl and incremental reserves were again two million barrels of oil. The difference in economics shows the value of the advanced reservoir characterization.

PROJECT AREA PREPARATION

CO_2 supply and distribution systems were designed and material specifications completed. The specifications were used to solicit bids for the materials. Successful bidders were selected and materials ordered.

OXY engineers used the information from the simulation model to design facilities. The model provided rates and pressures for each row of injection wells. A minimum and maximum injection rate and a maximum bottomhole injection pressure were specified for each injection well. The line sizing and wellhead fittings were then specified to keep the pressure differentials to less than 20 psi per mile and thus keep velocities to a minimum. Pressure losses from vaporization are to be avoided by keeping line pressures above the CO_2 critical pressure.

Each injection well assembly is comprised of a line blind (for changing to and from water and CO_2 injection) a line strainer turbine meter and manual choke assembly. Where the piping could be exposed to water, stainless steel was used instead of carbon steel. Additionally, supply meter locations use A333-Grade 3 or 6 piping due to the low temperatures expected during blowdown and depressurization.

Also, the production and gas gathering facilities are being upgraded to allow more detailed measurement of the produced fluids. The gas gathering system will deliver the total produced gas stream to the Welch gas plant for: 1) removal of the natural gas liquids (NGL) consisting of propane, and heavier components, 2) compression, and 3) return of the CO_2 volume contaminated with residue gas for reinjection. The contaminated gas will have a higher miscibility pressure of about 1450 psi than the original 1200 psi for pure CO_2.

The reduction in injection pressure mentioned under Numerical Simulation was achieved by temporarily shutting in all 18 active injector wells in the project area. The wells were returned to injection at rates which kept the surface pressure below the target established by utilizing results of 7-step rate tests that have been run recently. In addition, producing wells WWU4846 and WWU4832 were worked over. Pre-workover injection surveys were run on WWU4807w and WWU4816w.

WWU4854 was completed during the second quarter of 1997 to complete the south injection pattern (Figure 4). Well logs from WWU4854 along with previous fracturing work [4] were used to create a fracturing model for design of the fracture treatment for this well.

TECHNOLOGY TRANSFER

During the third annual reporting period, seven presentations were made before various industry groups. In addition, two poster session were conducted at technical meetings. One technical has been published by team members on various aspects of the project [5].

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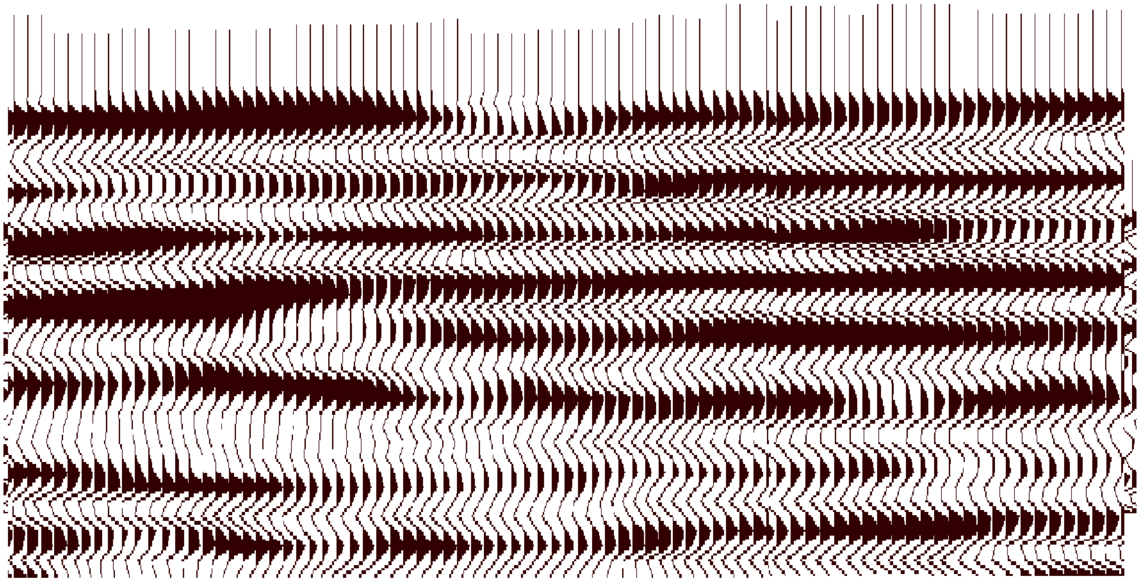

Figure 1 Portion of the cross well reflection survey between wells 7916 and 7914.

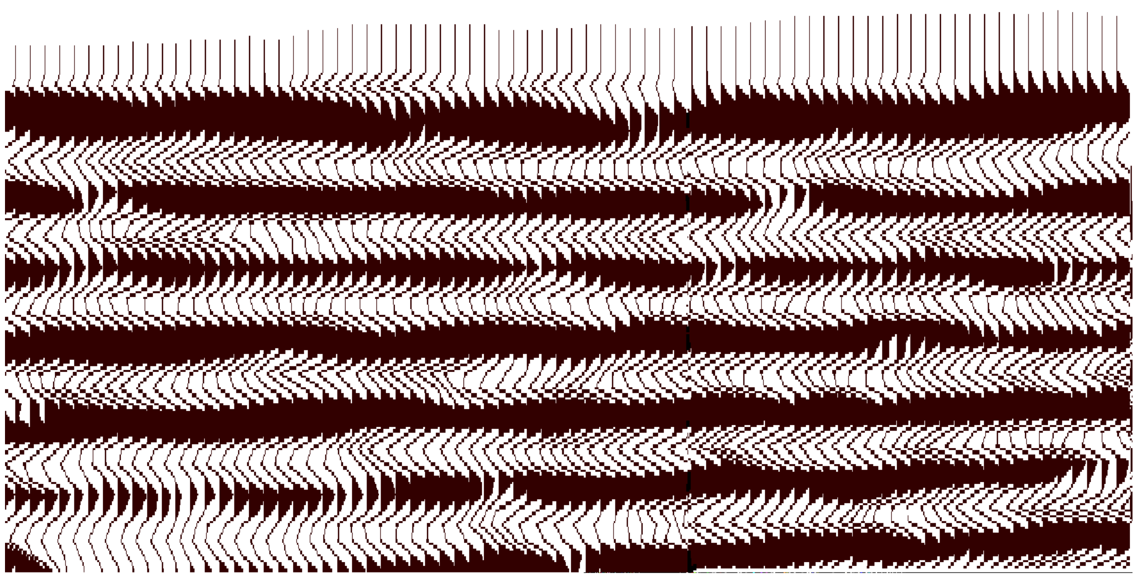

Figure 2 Portion of the cross well reflection survey between wells 4852 and 4809.

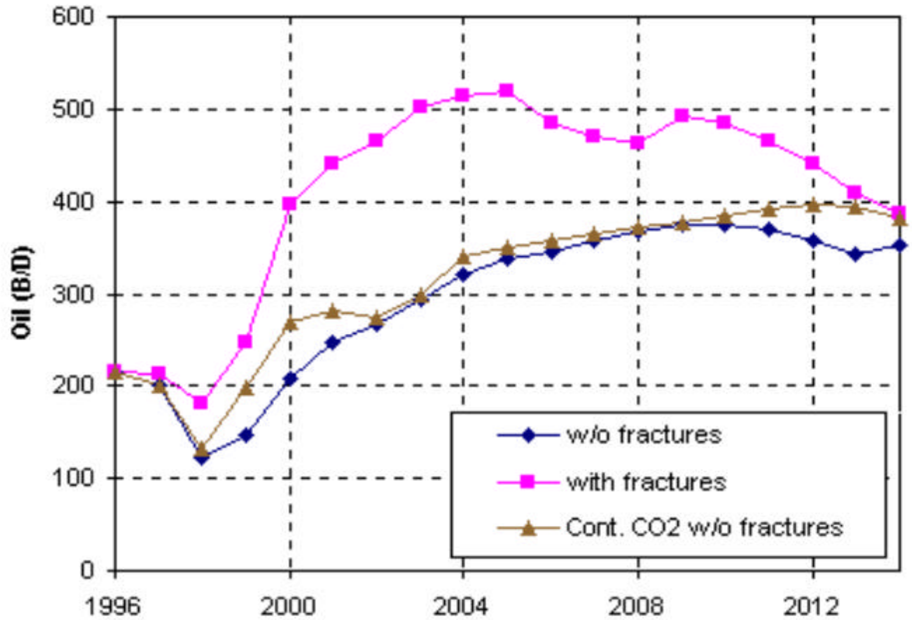

Figure 3 Simulation model forecasts for various operating scenarios.

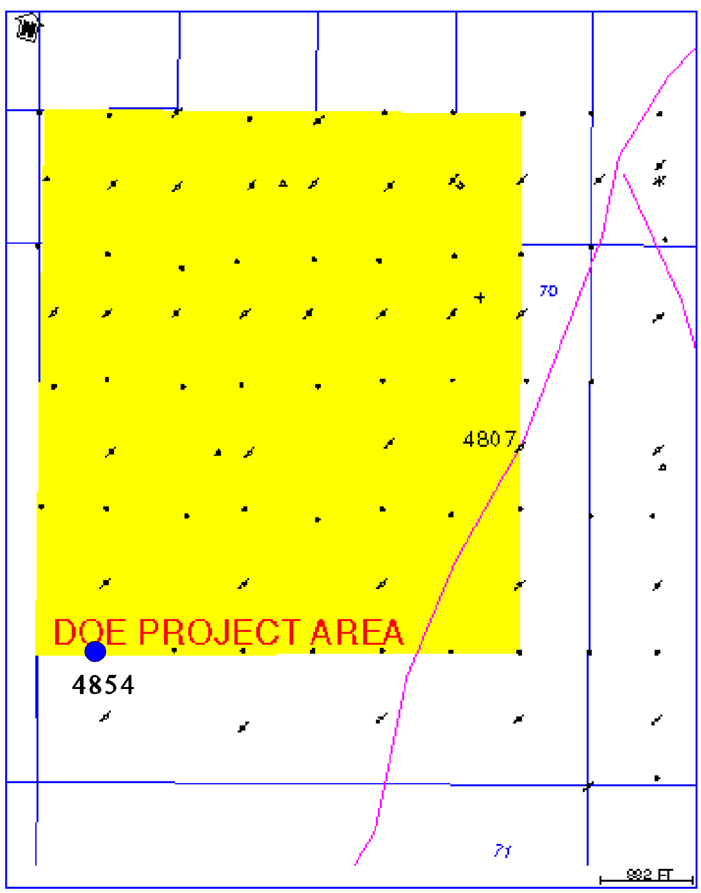

Figure 4 Location of the #4854 well.